Final

Permit Review
Chapter 127

To: Mark J. Wejkszner
Program Manager

Through: Raymond Kempa
Chief, New Source Review Section

From: Brian Halchak
APCE III

Date: March 4, 2009

Region 2	Luzerne County
Permit Number	40-328-006
Company Name	UGI Development Company Hunlock Power Station
Source Description	Two (2) GE LM6000 combined-cycle combustion turbines, two (2) HRSG, one (1) auxiliary boiler 500,000 gallon storage tank, 10,000 gallon storage tank
Control Equipment	Selective Catalytic Reduction, CO Catalyst
Location of Sources	Hunlock Township, Luzerne County

THE COMPANY HAS SUBMITTED THE FOLLOWING DOCUMENTATION AS REQUIRED FOR THE PLAN APPROVAL TO BE COMPLETE:

a. A completed Air Pollution Control Act Compliance Review Form dated June 11, 2008.
b. Municipal notification received by the host municipality on June 24, 2008 as required by Act 14.
c. Municipal notification received by the host county on June, 24, 2008 as required by Act 14.
d. A check in the amount of $5,100 consistent with Subchapter I of Chapter 127 of the Rules and Regulations of the Department of Environmental Protection.
e. The General Information Form was submitted as part of the application on June 11, 2008.

THE DEPARTMENT HAS TAKEN THE FOLLOWING ADMINISTRATIVE ACTIONS:

a. The Application Acceptance/Administrative Completeness Letter was sent on July 3, 2008.
b. Coordination with other agencies was done and is not required.
c. Notification in the Pennsylvania Bulletin on July 19,2008 to allow an additional 30-day comment period for the public to respond. No comments have been received from the public or other agencies.
d. Additional technical information required letter dated August 27, 2008
e. Received additional information requested from UGI development Hunlock Station February 2, 2009.

GENERAL INFORMATION:

UGID is proposing to construct and operate a combined-cycle power plant at the Hunlock site located about 10 miles south of Wilkes-Barre, Pennsylvania in a rural setting in Hunlock Township, Luzerne

County. The facility is arranged on an approximately 60-acre parcel of land next to the west bank of the Susquehanna River's North Branch. The project will replace the existing Unit 3 coal-fired boiler (the "Project"). The coal-fired boiler will be retired in place. The new combined-cycle plant will consist of:

Major equipment associated with the Project includes:

- Two GE LM6000 PC-Sprint CTGs (designated as Units 5 and 6).
- Two (2) supplementary natural gas-fired HRSGs with separate exhaust stacks (one for each Combustion Turbine ("CT")
- Use of existing STG (steam turbine generator)
- Nominal 500,000-gallon capacity low sulfur distillate storage tank
- A natural gas-fired package boiler (< 50MMBtu/hr) to provide heat to the existing administration building and related plant facilities
- Nominal 10,000-gallon capacity aqueous ammonia storage tank
- Demineralized water storage tank, nominally 150,000-gallon capacity

Each Combustion Turbine ("CT") will be arranged with a Heat Recovery Steam Generator ("HRSG") that will generate steam using the heated exhaust from its associated CT, thus operating in combined-cycle mode. The CTs will burn natural gas as the primary fuel and low-sulfur distillate as an alternative fuel (approximately one month each year).

The steam from each HRSG will be fed to the existing (albeit refurbished) Unit 3 condensing STG to generate additional power. The HRSGs will have supplemental duct-firing capability (utilizing only natural gas) to increase steam and, therefore, power output primarily during periods of peak demand. The proposed state-of-the-art combined-cycle electric generating facility designed to generate approximately 122 MW (net, average annual) of electricity. Two GE LM6000 PC-Sprint combustion turbines are proposed as the prime mover for the Project.

PROCESS DISCRIPTION:

The Project will use combined-cycle power generation technology to maximize generation efficiency and minimize fuel usage. This technology is nearly 30% more efficient than vintage steam-electric utility power plants. Since combined-cycle units burn less fossil fuel to generate an equivalent amount of power, they also emit substantially less air pollutants, including greenhouse gases such as carbon dioxide ("CO_2"). The Project primary fuel will be pipeline natural gas. Low sulfur (0.05% wt. S) distillate will be used as a secondary fuel. The combustion turbine will use water injection to minimize the formation of nitrogen oxides ("NO_x") during the combustion process.

In a combined-cycle facility, fuel is fired in a CT. The expanding exhaust gas turns a rotor that is attached to dedicated electric generators (i.e., the generator portion of the CTG) and thereby producing electricity. The hot exhaust gas leaving the CTs is then used to convert water to steam in each HRSG. For this project, the HRSGs will include natural gas-fired duct burners to increase the CT exhaust gas temperature and plant capacity

Combustion Turbines

The CT is the core component of a combined-cycle power system. For this project, two GE LM6000 PC Sprint CTs are proposed. Each CT will be connected to a dedicated electric generator that will produce nominally 50 MW each.

First, air is filtered and compressed in a multi-stage axial-flow compressor. Compressed air and fuel are mixed and combusted in the CT chamber. Exhaust gas from the combustion chamber is then expanded through a multi-stage power turbine that drives both the inlet air compressor and an electric power generator. The combustion chamber is equipped with a water injection system to minimize NO_x formation during combustion. Highly purified water is injected into the combustion chamber prior to combustion lowering the peak flame temperatures and thus reducing the formation of thermal NO_x.

Heat Recovery Steam Generators

The Project design includes two supplementary-fired HRSGs. In a combined-cycle facility, a HRSG extracts heat from the CT exhaust gases to produce steam that is used to drive a STG. The HRSGs will include a two-pressure steam system and the proposed emission control systems. The proposed emission control systems are carbon monoxide ("CO") oxidation catalyst and selective catalytic reduction ("SCR") systems. The heat extraction process will cool the flue gases that enter the HRSGs at approximately 850°F to approximately 200°F prior to release through the HRSG stacks. Separate nominal 192-foot tall exhaust stacks are proposed.

The HRSG duct burners will be natural gas-fired only with a rated capacity of 38.9 MMBtu/hr. Operations of the HRSG duct burners will be limited to 77.8 MMscf/yr per unit which is equivalent to 2,000 hrs/yr.

Steam Turbine

The Project will use the existing Boiler #6 STG associated with Unit 3. Steam produced in the HRSGs will be expanded in the STG to drive a dedicated generator that will produce electricity. The STG has a nominal rating of 50 MW.

Fuel Systems

Natural gas will be the CT's primary fuel and will be the sole fuel for the HRSG duct burners and steam boiler. The natural gas used by the facility will vary according to pipeline supply conditions. For purposes of emission calculations, the natural gas is assumed to have a nominal higher heating value ("HHV") of 1,000 Btu/scf and a maximum sulfur content of 0.8 grains per 100 scf.

Low sulfur (0.05% wt. S) distillate fuel oil will be used as the secondary fuel by the CTs. A new nominal 500,000-gallon capacity low sulfur distillate fuel oil tank will be installed. Low sulfur distillate usage will be limited to 1,955.5 Kgal/yr per unit, which is equivalent to 600 hrs at 100% load.

CONTROL EQUIPMENT:

Combustion Turbine Emissions Control Techniques

The Project will include air pollution control equipment to comply with State BAT requirements as applicable, for each significant air pollutant. The control technologies to be employed are summarized below.

Nitrogen Oxides – The Project will control NO_x emissions by means of water injection in conjunction with SCR.

Carbon Monoxide – CO emissions will be controlled by a oxidation catalyst and good combustion practices.

Sulfur Dioxide ("SO_2") – SO_2 and other sulfur emissions such as sulfuric acid ("H_2SO_4") mist will be minimized by the use of pipeline quality natural gas and low sulfur (0.05% wt. S) distillate.

Particulate Matter ("PM") – Particulate emissions will be minimized by the use of pipeline quality natural gas, low sulfur (0.05% wt. S) distillate, and efficient combustion.

Volatile Organic Compounds ("VOC") – VOC emissions will be controlled by good combustion practices. While it is expected that the oxidation catalyst will provide up to approximately 40% control of VOC, this reduction level is not guaranteed by the catalyst vendors and has not been accounted for in the emission estimates.

Hazardous Air Pollutants ("HAP") – HAP emission will be controlled by a combination of the use of pipeline quality natural gas, low sulfur (0.05% wt. S) distillate, good combustion practices, and the use of an oxidation catalyst. HAPS consisting of heavy metals will be minimized by the use of natural gas low sulfur (0.05% wt. S) distillate, and good combustion practices. Organic HAPS, such as formaldehyde, which are mostly the result of incomplete combustion will be minimized by the oxidation catalyst and efficient combustion.

OTHER SOURCES:

Ammonia Storage

Aqueous ammonia injection will be used to facilitate NO_x control in the SCR system.. The Project specification is for 19% aqueous ammonia. The ammonia will be stored in a nominal 10,000 gallon aqueous ammonia tank on the Project property.

Steam Boiler

A natural gas-fired boiler (utilizing less than 50 MMBtu/hr, nominal) is proposed to provide heat to the existing administration building and related plant facilities building. This unit will replace two existing 20,000 lb/hr oil-fired auxiliary boilers. Note that emission reductions from these existing units are not included in the PSD and NNSR netting analyses.

Project Emissions

The emission calculation methodologies used rely on manufacturer's data, expected control technology efficiencies, fuel specifications, and standard emission factors from USEPA AP-42. Unit design parameters and operational practices and limitations have been incorporated into the analyses to make the emissions estimates realistic and representative of onsite conditions.

GE provided UGID with estimated operational data for normal operating conditions for the combustion turbine, including pollutant concentration levels, turbine heat input and combustion turbine exhaust gas analysis from full load to 50% of full load. This load range is defined as the normal operating range of the unit. Final pollutant concentrations and mass emission rates were developed by UGID for this operating range based on the vendor supplied combustion turbine emissions data, proposed emission control systems, fuel specifications, and standard emission factors. Pound per hour mass emission rates as provided by GE are based on new and clean equipment. The Project has added a 10% margin to the vendor supplied mass emission rates to account for variations in ambient conditions and equipment degradation over time.

- NO_x emissions are based on controlled, in-stack pollutant concentrations of 3.5 ppmvd at 15% O_2 (natural gas normal operations), 4.0 ppmvd at 15% O_2 (natural gas normal operations, with duct-firing), 9.0 ppmvd at 15% O_2 (low sulfur distillate), and 9.5 ppmvd at 15% O_2 (low sulfur distillate, with duct-firing). In-stack NO_x concentration levels will be guaranteed over the range of normal operating conditions.

- CO emissions are based on controlled, in-stack pollutant concentrations of 20.0 ppmvd at 15% O_2 (natural gas normal operations with and without duct-firing) and 5.0 ppmvd at 15% O_2 (low sulfur distillate normal operations, with and without duct-firing). In-stack concentration levels will be guaranteed over the range of normal operating conditions.

- VOC emissions are based on in-stack pollutant concentrations of 4.0 ppmvd @ 15% O_2 (natural gas normal operations with and without duct-firing) and 8.0 ppmvd at 15% O_2 (low sulfur distillate normal operations, with and without duct-firing). In-stack concentration levels will be guaranteed over the range of normal operating conditions.

- SO_2 emission rates are based on vendor provided fuel consumption rates, a worst-case fuel sulfur content and nominal fuel Btu content. All fuel sulfur is assumed to be emitted as SO_2.

- H_2SO_4 emissions were estimated based on the SO_2 emission rate, an assumption that up to 30% of the SO_2 will oxidize to SO_3 across the oxidation catalyst, and that all the SO_3 will combine with water vapor in the stack to form H_2SO_4. Note that the SO_2 emission rate does not take any credit for this conversion of SO_2 to H_2SO_4; therefore, the SO_2 and H_2SO_4 emission rates double-count a portion of the fuel sulfur.

- PM_{10} emission rate is based on vendor supplied non-condensable particulate matter (PM) emission rate and an estimate of condensable particulates. To estimate condensable PM_{10} emissions, it is conservatively assumed that all SO_3 combines with NH_3 to form ammonium sulfates. This effectively triple-counts the SO_3 as SO_2, H_2SO_4, and condensable particles. $PM_{2.5}$ emissions are assumed to equal PM_{10}.

- Hazardous air pollutant (HAP) emissions were estimated using emission factors from AP-42.

- Additional emissions from duct firing are based on vendor estimated emission factors and the assumed SCR and CO catalyst control efficiencies.

Whenever the Plant is dispatched, UGID expects to operate the combustion turbines at or near the 100% (Base) load case for the majority of the time. However, to provide operational flexibility, UGID has evaluated emissions over a potential range of normal turbine operating modes. Excess emissions attributable to combution turbine startup and shutdown were also evaluated based on vendor supplied data.

For the LM6000 turbine, UGID proposes a normal operating range of between approximately 50 and 100% load for both the primary and secondary fuels. In addition to operating load, combustion turbine emissions vary with ambient temperature. UGID evaluated combustion turbine operating parameteres at five ambient temperatures, -10°F, 25°F, 50°F, 75°F, and 85°F.

The combustion turbine will also have the capability of using inlet chilling to cool the inlet air to increase power generation at ambient temperatures above 50°F. Inlet chilling will use an absorption chiller, with low pressure motive steam from the steam turbine cycle, to generate chilled 45°F water. The chilled water will pass through heat exchanger coils at the inlet of the turbine, cooling the incoming air to approximately 50°F. Note that this operating mode was not individually investigated. While performance with inlet chilling will impact stack gas exit parameters, the effected parameters are within the range of conditions investigated

The maximum worst-case short-term emission rates for the LM6000 combined cycle combustion turbine system is presented in the table below.

Combustion Turbine Fuel	*Natural Gas*	*Natural Gas*	*Low Sulfur Distillate*	*Low Sulfur Distillate*
Duct Burner	No	Yes	No	Yes
Pollutant	Maximum Hourly Emission Rate (lbs/hr)			
NO_x	6.6	7.7	19.5	17.2
CO	21.8	23.5	2.5	2.3
SO_2	1.1	1.2	23.0	23.1
PM_{10}	5.1	5.6	30.8	31.2
VOC	2.6	2.7	5.3	5.7
H_2SO_4	0.49	0.54	10.5	10.6
NH_3	6.9	7.1	7.1	7.6

STARTUP/ SHUTDOWN

As stated, the Project has defined the normal operating range for the LM6000 combustion turbine as between 50 to 100% load. During normal operation, the turbines will meet the emission limitations as defined by control technology review. During periods of startup, shutdown, or malfunction, combustion turbine emissions of certain pollutants will be elevated until the combustion turbine and emission control systems reach steady-state operation.

Pollutants most likely to be effected are CO, NO_x and VOC. SO_2 emissions are strictly a function of fuel usage and therefore are not elevated during startup or shutdown. No data exists for particulate emissions during startup, however, since a significant portion of the PM_{10} emissions are condensable particulates, mostly ammonium sulfates. PM_{10} emissions are not expected to be elevated above permitted levels during startup or shutdown.

Startup and shutdown emission estimates for typical operations under ISO conditions were provided by GE. Based on the data provided by GE:

- A typical startup, defined as from initial fuel firing to combustion turbine steady state operation, is expected to take approximately 1 hour.
- A typical shutdown, defined as from when steady state combustion turbine operating load falls below normal operations to cessation of fuel firing, is expected to take approximately 30 minutes.

- Peak CO and NO_x concentrations are expected to average less than 100 ppmvd @ 15% O_2 over the startup/shutdown period.
- During the startup/shutdown period, actual emissions will be greater than steady-state controlled emissions.
- The avoided emissions that would have occurred had the unit not undergone a startup/shutdown sequence and been operating at normal base load conditions are greater than the elevated startup/shutdown emissions. Therefore, annual tpy emissions are "self-correcting".

The following table represents the total emissions for the facility

Operating Scenario	*Annual Pollutant Emissions (tpy)*							
	NO_x	*CO*	*VOC*	*SO_2*	*PM_{10}*	*TSP*	*H_2SO_4*	*NH_3*
Combustion Turbines	65.7	56.4	24.5	22.7	42.3	41.7	10.4	60.7
Steam Boiler	1.8	4.2	0.3	0.1	0.4	0.1	Neg	0.0
Storage Tank	0.0	0.0	0.008	0.0	0.0	0.0	0.0	0.0
Project Total	67.5	60.6	24.8	22.8	42.7	41.8	10.4	60.7

Nonattainment Area NSR Applicability:

25 Pa. Code Chapter 127, Subchapter E contains requirements for sources located in a non-attainment area. Emissions of ozone precursors VOC and NOx are potentially subject to non-attainment NSR ("NNSR"). Luzerne County is designated as an attainment area for PM2.5 therefore NNSR applicability is not required. The applicability threshold for NNSR is: VOC 50 tpy, NOx 100 tpy. NSR Applicability is two steps program:

Step 1: Calculation of the emissions increases of each regulated NSR pollutant due to the project
Step 2: Net Emissions Increase Calculation

Step 1:
The term "project" is defined at 25 Pa. Code Section 121.1 as a physical change in or change in the method of operation of an existing facility, including a new emissions unit. Therefore, a project includes new emissions units, modifications to existing emissions units, replacement units and de-bottlenecked units.

Major equipment associated with the Project includes:

- Two GE LM6000 PC-Sprint CTGs (designated as Units 5 and 6).
- Two (2) supplementary natural gas-fired HRSGs with separate exhaust stacks (one for each Combustion Turbine ("CT")
- Use of existing STG (steam turbine generator)
- Nominal 500,000-gallon capacity low sulfur distillate storage tank
- A natural gas-fired package boiler (< 50MMBtu/hr) to provide heat to the existing administration building and related plant facilities
- Nominal 10,000-gallon capacity aqueous ammonia storage tank

- Demineralized water storage tank, nominally 150,000-gallon capacity

The following table represents the total emissions for NSR regulated pollutant due to the project:

Emissions Units		***Method for determining emissions increase***	*NO_x*	*VOC*
Combustion Turbines	New Emissions Unit	Potential to Emit	65.7	24.5
Steam Boiler	New Emissions Unit	Potential to Emit	1.8	0.3
Storage Tank	New Emissions Unit	Potential to Emit	0.0	0.008
Project Total	New Emissions Unit	Potential to Emit	67.5	24.8

Step 2: Net Emissions Increase Calculation

Since NOx emissions increase due to the project exceeds the listed applicable rate; we will use provisions of §127.203a(a)(1)(ii) to calculate net emissions increase.

§127.203a(a)(1)(ii): (Similar to Federal NSR)

Net Emissions increase =
Plus Increase in emissions due to the project (65.7 tpy of NOx)

Plus Other increases in actual emissions occurring within the 5-year period. (0 tpy)

Minus Other decreases in actual emissions occurring within the 5-year period. (472.6 tpy)

= -406.9 tpy of NOx

Since VOC emissions due to the project does not exceed the the listed applicable rate; we will use provisions of §127.203a(a)(2) to calculate net emissions increase. ("De minimis emissions increase calculation")\

§127.203a(a)(2): (De minimis emissions increase calculation)

Net Emissions increase =
PlusProposed de minimis emissions increase due to the project (24.8 tpy)

Plus Other previously determined increases that occurred within
10 years prior to the date of a complete plan approval application. (please provide)

Minus Other decreases in actual emissions that occurred within
10 years prior to the date of a complete plan approval application. (- 5.3 tpy)

= 19.2 tpy of VOCs

Since the *net emissions increase* is below the 40 tpy of NOx and VOCs NSR triggering threshold, the proposed project is not subject to the NNSR regulations. Thus, the proposed project has netted out of NSR.

Prevention of Significant Deterioration

Prevention of Significant Deterioration ("PSD") review (40 CFR 52.21) is a federally mandated program that applies to new major sources of regulated pollutants and major modifications to existing sources. PSD review is a pollutant-specific review that applies only to those pollutants for which a project is considered major and the project area is designated as attainment or unclassified.

Since the existing facility is a major source per the PSD regulations, PSD review would apply if the proposed project is a major modification. To make this determination, a PSD applicability analysis was conducted to determine if the Project would result in a significant net increase of any regulated pollutant. This analysis took into account emission increases attributable to the installation of new equipment, specifically the combustion turbines/duct burners, auxiliary steam boiler, and the low sulfur distillate storage tank and emission decreases associated with the shutdown of Unit #6, the existing coal-fired boiler.

Unit #6 will continue to operate for a period of time while the combustion turbines are being installed. Since the existing Unit #6 steam turbine will be used by the Project, Unit #6 will need to shutdown prior to startup of the Project to allow for the completion of the necessary connections between the HRSGs and the steam turbine. Once Unit #6 is shutdown, UGID has filed the appropriate Emission Reduction Credit (ERC) forms for the Boiler #6 and the netting analysis and ERC have been incorporated into the plan approval.

The Project will also include the installation of a new <50 MMBtu/hr natural gas-fired steam boiler. This unit will replace two existing 20,000 lb/hr oil-fired boilers. Emission increases associated with the new natural gas-fired unit are included in the netting calculation. However, as the exact timing of the installation of this new unit and shutdown of the existing units is unknown in relationship to the startup of the combustion turbines, emission reductions associated with the shutdown of the existing auxiliary boilers are not included. UGID will file the appropriate ERC forms at the time these units are shutdown.

The following table shows the netting analysis for the shut down of Boiler #6 and the new project emissions:

Pollutant	*PSD Significant Emission Rate (tpy)*	*Project Emission Increases (tpy)*	*Boiler #6 Emission Decrease (tpy)*	*Net Emissions Increase (Decrease) (tpy)*	*PSD Modification*
Carbon Monoxide	100	60.6	42.1	14.4	No
Nitrogen Oxides	40	67.5	472.6	-406.9	No
Sulfur Dioxide (SO2)	40	22.8	4497.7	-4474.9	No
Particulate Matter (TSP/PM)	25	41.8	17.2	24.6	No
PM10	15	61.7	278.4	-217.1	No
PM2.5		61.7	278.4	-217.1	No
Ozone (Volatile Organic Compounds)	40	24.7	5.3	19.2	(1)
Lead	0.6	0.002			No
Asbestos	0.007	NA			No
Beryllium	0.0004	0.00004			No
Mercury	0.1	0.0002			No
Vinyl Chloride	1	NA			No
Fluorides	3	NA			No
Sulfuric Acid Mist	7	10.4	3.7	6.7	No
Hydrogen Sulfide	10	NA			No
Total Reduced Sulfur Compounds	10	NA			No
(1) Area is designated as nonattainment for ozone; therefore, PSD is not applicable to this pollutant.					

REGULATORY ANALYSIS:

40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines ("Subpart KKKK")

Subpart KKKK establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Subpart KKKK applies to stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005. Only heat input to the combustion turbine is included when determining applicability of subpart KKKK. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners are not included when determining peak heat input. However, subpart KKKK does apply to emissions from any associated HRSG and duct burners.

Subpart KKKK contains emission standards for NO_x and SO_2 in addition to notification, monitoring, testing, and reporting requirements. The applicable NO_x standard for a new turbine firing natural gas with a heat input rate of between 50-850 MMBtu/hr is 25 ppmvd corrected to 15% O_2 or 150 ng/J of useful output (1.2 lb/MWh). The applicable SO_2 standard is an emission limit of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or a fuel sulfur limitation of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

The proposed NO_x emission rates for the Project will be well below the NSPS emission limit. In addition, the Project will meet the SO_2 requirement by burning pipeline quality natural gas and low sulfur (0.05%) distillate. The natural gas is expected to contain no more than 0.8 grains per 100 scf of natural gas (less than 0.002 % sulfur by weight). Therefore, the fuel sulfur content for the Project will be well below the NSPS requirements.

40 CFR 60 Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Subpart Dc applies to each steam generator that commences construction or modification after June 9, 1989 and that has a heat input capacity in the steam-generating unit between 10 and 100 MMBTU/hr. The steam boiler will generate steam and have a nominal heat input of less than 50 MMBTU/hr. Although the steam boiler will be subject to Subpart Dc, there are no specific requirements resulting from Subpart Dc for units that combust only natural gas. Therefore only the general notification and reporting requirements of the NSPS (Subpart A) are applicable to the auxiliary boiler.

National Emission Standards for Hazardous Air Pollutants ("NESHAP")

40 CFR 63 Subpart YYYY National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines applies to stationary combustion turbines located at major sources for HAPs. With the shutdown of Boiler #6, the Facility will no longer be a major source of HAPs. The Project itself will be a minor source of HAPs. Therefore, the project is not subject to NESHAP regulation.

Acid Rain Program

The Project includes construction of new electric utility generating units. The proposed units will be fossil fuel-fired combustion devices used to generate electricity for sale and, therefore, are "affected units" as defined under the Acid Rain Program. The requirements for affected units under the Acid Rain Program, established pursuant to Title IV of the Clean Air Act (CAA), are covered under 40 CFR 72 through 78. The Project will be subject to the requirements of 40 CFR 72 and 40 CFR 75.

<u>40 CFR 72 – Permits Regulation</u>

All utility generating units greater than 25 MW are required to obtain a Phase II Acid Rain Permit. In order to obtain the permit the facility must obtain a Facility Code from the Energy Information Agency of the Department of Energy, apply for the permit on EPA forms, and identify the Designated Representative, per 40 CFR 72.20.

Subpart A of 40 CFR 72 requires a facility to have a Designated Representative who represents and legally binds the owners and operators in matters pertaining to the acid rain program. The authority of representation must be obtained by filing a certificate of representation with the U.S. Environmental Protection Agency (EPA) Administrator. The Designated Representative is required to submit an acid rain permit application at least 24 months before the date on which the unit is to commence operation[1]. The facility must operate in compliance with the permit application until superceded by an acid rain permit.

40 CFR 72 also requires the facility to hold allowances (in the unit's compliance sub-account) equivalent to the total annual emissions of SO_2 for the previous calendar year. UGID is aware of these requirements and will obtain the necessary allowances.

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40 CFR 75 – Continuous Emission Monitoring

This part of the acid rain regulations specifies the requirements for monitoring, record keeping, and reporting. The pollutants and parameters covered under 40 CFR 75 are SO_2, NO_x, and carbon dioxide ("CO_2") emissions, as well as volumetric gas flow and opacity. The regulations require the installation of continuous emission monitors ("CEM") to measure these parameters except:

- Gas and oil fired units can monitor SO_2 per Appendix D methodology in lieu of SO_2 and flow CEM. If the fuel is pipeline quality natural gas an emission factor of 0.0023 lb/MMBTU can be utilized to calculate lb/hr.
- Gas-fired units are exempt from the opacity monitoring requirements. Gas-fired units are defined as any unit that combusts at least 90 % over a three year (or 85 % in any one year) natural gas.
- Facilities can monitor O_2 and use F-factors to estimate CO_2 emissions.
- Peaking units (less than 20% in any one-year and 10% in any three-year period) are exempt from the requirements to install CEM (this is not applicable to this facility).

All monitoring systems must be installed and certified within 90 days of the turbine commencing commercial operations. In addition, 40 CFR 75 outlines heat input measurement requirements. The Project will develop and implement a monitoring plan to comply with 40 CFR 75.

Accidental Release Program

The Accidental Release Program promulgated under Section 112(r) (40 CFR 68) of the 1990 Clean Air Act Amendments is applicable to the storage and handling of chemicals identified as extremely hazardous substances. The only chemical currently envisioned for use at the site subject to the requirements of 112(r) is ammonia.

The project is proposing to use aqueous ammonia in the SCR system to control NO_x emissions. The aqueous ammonia will be 19% ammonia by weight. The aqueous ammonia system associated with the SCR control is not subject to 112(r). This is because the regulations apply to aqueous ammonia solutions of 20% or greater by weight ammonia.

State Regulations

PA Code §123 Standards For Contaminants

The Project will be subject to the following standards per §123:

- §123.11 Particulate Emission Standards: Combustion Units. The combustion turbine is limited to a particulate matter emission rate of 0.1 pound per million Btu of heat input. The steam boiler is limited to a particulate matter emission rate of 0.4 pound per million Btu of heat input. UGID will comply with these limits through the use of natural gas and low sulfur fuel oil.

- §123.22 Sulfur Compound Emissions: Combustion Units. The sulfur content is limited to a maximum of 0.3%. UGID is proposing to use low sulfur distillate in the combustion turbine with a sulfur content of 0.05%.

- §123.31 Odor: Control of odor is regulated such that malodors must not be detectable outside the property boundary. UGID will operate the proposed units according to manufacturer's specification. Therefore, malodors from these units are not expected to be detectable.

- §123.41 Visible Emissions. The opacity of the emission is either of the following:
  1. Equal to or greater than 20% for a period or periods aggregating more than 3 minutes in any 1 hour.
  2. Equal to or greater than 60% at any time.

  UGID will comply with these limits through the use of pipeline quality natural gas and low sulfur distillate.

- §123.51 Nitrogen Compounds: Install, operate and maintain continuous nitrogen oxides monitoring systems and other monitoring systems to convert data to required reporting units in compliance with Chapter 139, Subchapter C

- §123.101-121 NO_x Allowance Requirements – UGI will hold a quantity of NO_x allowances as required

- §§145.1-145.90 NO_x Budget Trading Program - Monitor emissions, hold and surrender allowances, submit compliance certification reports

PA Code §127 Construction, Modification, Reactivation, and Operation of Sources

Per PA Code §127 Subchapter B, the proposed Project will require a plan approval. Plan approval requirements are summarized in §127.12. This application presents the information required for the plan approval application.

Subchapter D requires that PSD applicability be assessed. A PSD applicability analysis was performed (see Section 3.1). The results of this analysis demonstrate that the Project is not subject to PSD review.

Subchapter E contains requirements for sources located in a non-attainment area. The area surrounding the UGID facility is designated as marginal non-attainment for ozone. As such, emissions of ozone precursors VOC and NOx are potentially subject to non-attainment NSR ("NNSR"). The applicability threshold for NNSR is: VOC 50 tpy, NOx 100 tpy. Similar to PSD review, NNSR applicability is based on an emissions netting analysis which is summarized in Table above. The results of this analysis demonstrate that the project is not subject to NNSR.

Subchapter F and G contain requirements for Title V operating permits. The Project will will file a Title V application within the required timeframe.

MONITORING, TESTING AND RECORDKEEPING REQUIREMENTS:

A continuous emissions monitoring system will be installed to provide monitoring of stack emissions for NO_x, CO, and oxygen. The emissions monitoring system will provide input signals to a microprocessor-based data acquisition system and will meet the regulatory requirements for monitoring and reporting.

SPECIAL CONDITIONS:

The following table are the BAT limits imposed on the facility for the combustion turbines

Pollutant	*Control Level*	*Control Technology*	*Emission Limitation*[(1)]
NO_x	State BAT	• Water Injection • Selective Catalytic Reduction	• 3.5 ppmvd at 15% O_2 – Natural gas, normal operation • 4.0 ppmvd at 15% O_2 – Natural gas, with duct-firing, normal operation • 9 ppmvd at 15% O_2 – low sulfur distillate, normal operation • 9.5 ppmvd at 15% O_2 – low sulfur distillate with duct-firing, normal operation
CO	State BAT	• Oxidation Catalyst • Good Combustion Practices	• 20 ppmvd at 15% O_2 – Natural gas, normal operation • 2 ppmvd at 15% O_2 – low sulfur distillate, normal operation
VOC	State BAT	• Good Combustion Practices • Oxidation Catalyst	• 4 ppmvd at 15% O_2 – Natural gas, normal operation • 8 ppmvd at 15% O_2 – low sulfur distillate, normal operation
PM_{10}	State BAT	• Good Combustion Practices • Clean Fuels	No numerical limit
SO_2 / H_2SO_4	State BAT	• Pipeline Quality Natural Gas	• 0.8 gr Sulfur per 100 scf Natural Gas • low sulfur distillate (0.5 wt % sulfur)
Ammonia Slip	State BAT	Automatic Control	• 10 ppmvd of Ammonia at 15% O_2
Opacity	State BAT	Good Combustion	• < 10%

(1) Proposed limits are for normal operations (50-100% load). These limits do not apply during periods of startup, shutdown, fuel transfer, or malfunction.

RECOMMENDATION:

Based on the review of the plan approval application and all the supplemental information supplied to the Department by the company. The proposed project appears to comply with the requirements of State and Federal regulations. Therefore, I recommend that a plan approval shall be issued for the construction of the two new turbines.